DIRECT TESTIMONY OF
MARGOT EVERETT
ON BEHALF OF
DOMINION ENERGY SOUTH CAROLINA, INC.
DOCKET NO. 2019-182-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Margot Everett. My business address is 101 California Street, Suite 4100, San Francisco, California 94111. I am a Director for Guidehouse and will provide testimony on behalf of Dominion Energy South Carolina, Inc. ("DESC").

Q. BRIEFLY STATE YOUR EDUCATION, BACKGROUND, AND EXPERIENCE.

A. I have a Master of Science and Bachelor of Arts in Applied Economics from University of California, Santa Cruz. With over thirty-five years in the energy industry, I have held many differing roles from evaluation and design of customer programs, wholesale power contract structuring, market, credit and enterprise risk management and cost of service and rate design. Recently, I spent five years leading Pacific Gas and Electric's ("PG&E") electric and gas rates, load forecasting, and cost of service departments. In that role, I led the development and design of alternative rate designs for distributed energy resources, such as a net energy metering ("NEM") tariff.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA (THE "COMMISSION")?

A. I have not testified in South Carolina, but I have testified numerous times in California—in particular, on rate design policy and alternative rate designs. Further I supervised all testimony related to rates, cost of service, and load forecasting for the five years I served as Senior Director of Rates and Regulatory Analytics at PG&E.

Q. HAVE YOU INCLUDED ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes, I have included Exhibit No. __ (ME-1), which is a presentation report that shows our look at NEM rate structures in various states.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is threefold. First, I am sponsoring testimony regarding the value of solar methodology currently used in DESC's NEM programs, proposed changes to that methodology, and the current value of solar estimates. Second, I am presenting the required cost-benefit analysis of the current NEM tariff as required for this proceeding. This cost benefit analysis includes a review of current NEM programs, as well as the cost-effectiveness of the current NEM tariff design going forward, both over a ten-year horizon. Finally, I will present best practices in the industry for both value of solar methodologies and NEM programs, as requested in the Commission Directive issued in this docket on August 26, 2020.

Q. PLEASE DESCRIBE THE COST BENEFIT ANALYSIS REQUIRED BY ACT 62.

A. S.C. Code Ann. § 58-40-20(C)(1), as implemented by Act 62, requires a cost benefit analysis of DESC's current NEM programs. Act 62 expressly addresses the items which should be included in this analysis:

> (1) the aggregate impact of customer-generators on the electrical utility's long-run marginal costs of generation, distribution, and transmission;
> (2) the cost of service implications of customer-generators on other customers within the same class, including an evaluation of whether customer-generators provide an adequate rate of return to the electrical utility compared to the otherwise applicable rate class when, for analytical purposes only, examined as a separate class within a cost of service study;
> (3) the value of distributed energy resource generation according to the methodology approved by the commission in Commission Order No. 2015-194;
> (4) the direct and indirect economic impact of the net energy metering program to the State; and
> (5) any other information the commission deems relevant.[1]

Items (1) and (3) are aligned and require a systematic and repeatable methodology for quantifying short and long-term benefits and costs of distributed energy resources. Item (2) requires an analysis of differing impacts on customers,

[1] S.C. Code Ann. § 58-40-20(D).

and Item (4) indicates the need to review and assess whether there are "direct or indirect economic" benefits or costs that should be considered.

Therefore, the first step is developing this methodology that outlines each benefit and cost and then quantifying each of these benefits and costs. The second step is determining the impacts on different groups of customers, the utility, and the state of South Carolina. To accomplish these requirements, a systematic approach to assessing the impacts to each of the different groups of 'stakeholders' must be derived. In this case, there are four distinct groups of stakeholders that are impacted by the structure of a NEM tariff and have differing treatments of each element in the cost benefit analysis. For the purposes of the cost and benefit analysis under Act 62, these stakeholders include:

- Customers within the same class or outside the class of the customer-generation resource who have not installed behind the meter generation;
- The customer who installs the customer-generation resource;
- The utility; and
- South Carolinians.

The last step is then quantifying each of the components of costs and benefits and then quantifying the net benefits (benefits less costs) and benefit to cost ratio (benefits divided by costs) for each stakeholder group noted above.

Q. WHAT WAS YOUR APPROACH TO DETERMINING THE COMPONENTS OF BENEFITS AND COSTS TO INCLUDE IN YOUR ANALYSIS?

A. We looked at costs in four key categories:

- Generation costs: The costs to create or procure a kWh of energy, to include costs of building capacity to generate that kWh, cost related to maintaining system reliability and voltage control (e.g., Ancillary Services), and operating and maintenance costs related to emissions, particulates and other environmental cost as well as fuel costs and any related fuel hedging costs;
- Transmission and Distribution costs: The costs to deliver a kWh from a generator to the customer's meter;
- Integration and Interconnection costs: The costs related to connecting customers to the grid and integrating the customer's behind the meter generation with other generation resources; and
- Administrative costs: Costs associated with administering the NEM program.

Q. PLEASE DESCRIBE GENERATION RELATED COSTS.

A. Generation related costs include:

- Costs of building capacity to generate that kWh;

- Cost related to maintaining system reliability and voltage control (e.g., Ancillary Services);
- Cost associated with plant operations, such as Criteria Pollutants, CO2, and other emissions costs; and
- Fuel costs and any related hedging costs.

Q. PLEASE DESCRIBE TRANSMISSION AND DISTRIBUTION RELATED COSTS.

A. Transmission and Distribution related costs include:

- Costs of building transmission and distribution capacity; and
- Cost related to line losses resulting from moving electricity across the system from generation to the customer.

Q. PLEASE DESCRIBE INTEGRATION AND INTERCONNECTION COSTS.

A. Interconnection costs includes those related to connecting a customer's facility or home to the grid not covered in specific Interconnection Fees. Integration costs are those related to maintaining voltage levels and load following given variability in the customer's loads and customer-generation resource production.

Q. PLEASE DESCRIBE ADMINISTRATIVE COSTS.

A. Administrative costs include any additional costs the utility incurs to provide a NEM tariff, which may include costs related to billing practices or incremental customer call center support.

Q. YOU NOTED THAT ACT 62 REQUIRES REVIEW OF "DIRECT AND INDIRECT ECONOMIC IMPACT OF THE NET ENERGY METERING PROGRAM TO THE STATE." PLEASE DESCRIBE DIRECT AND INDIRECT ECONOMIC IMPACT.

A. Act 62 does not specifically define the components of direct or indirect economic impacts or provide guidance on computation of these benefits and costs. Nevertheless, we inferred that these impacts refer to the creation of economic growth, as measured in conventional economic growth metrics such as an increase in South Carolina's Gross Domestic Product ("GDP") and increases in job levels within South Carolina. Direct impacts from NEM implies that the program would be measurably responsible for creating GDP growth or new jobs while Indirect would be the secondary or tertiary impacts of NEM on these metrics.

The challenge with including these types of components is that they are extremely difficult to specifically measure and thus must be inferred through economic forecasting methodologies. That is, to measure, one has to be able to determine a "Base Case" what job levels and GDP would have been without the program and then compare that to what the actual job creation and GDP growth. This is not possible for the obvious reason that there is no direct way to compute these metrics for the "Base Case." Second, even if anecdotal evidence points to job growth or GDP growth, such as the increase in "solar related" jobs, it is not clear that increase is directly attributed to a NEM program versus other solar or renewable efforts encouraged by the State and utilities, such as wholesale solar or community solar. Lastly, it is important to remember that there may also be negative direct or indirect economic impacts from a program that result in higher rates for customers. Specifically, if a NEM program bill savings for a customer exceed the directly avoidable costs of the utility, the utility must still collect that deficit by raising rates for all customers. Rate increases can also have economic implications as monthly customers costs for electricity increase relative to income and other household expenses. This can result in customers having less disposable income to spend on other items, reducing sales, and—thus—profits for companies offering those items.

Q. ARE YOU RECOMMENDING ANY INCLUSION OF DIRECT OR INDIRECT IMPACTS IN THE BENEFIT COST ANALYSIS?

A. No. Given the challenges in measuring these impacts it is not possible to develop a credible, defensible, and transparent methodology for estimating these impacts.

Q. DOES DESC HAVE AN EXISTING EVALUATION METHODOLOGY FOR VALUING COSTS AND BENEFITS OF NEM?

A. Yes. Docket No. 2014-246-E established a methodology (the "NEM Methodology") that resulted in a valuation of each benefit and cost component for NEM (the "NEM Methodology Values"). The NEM Methodology Values are currently used for determining the incremental NEM incentive assigned to the Company's Distributed Energy Resource Program Incremental Costs for recovery purposes. The NEM Methodology was the result of a settlement (the "NEM Settlement") among the following parties:

- South Carolina Office of Regulatory Staff ("ORS");
- Duke Energy Carolinas, LLC;
- Duke Energy Progress, Inc.;
- South Carolina Electric and Gas Company (now DESC);
- Central Electric Power Cooperative, Inc.;
- The Electric Cooperatives of South Carolina, Inc.;
- South Carolina Coastal Conservation League;
- Southern Alliance for Clean Energy;
- South Carolina Solar Business Alliance, LLC;
- Sustainable Energy Solutions, LLC;
- Solbridge Energy, LLC;
- The Alliance for Solar Choice; and
- Sierra Club.

Q. WHAT IS THE NEM METHODOLOGY?

A. The NEM Methodology was established via the NEM Settlement, and includes defining eleven value components and specifying the methodology for calculating each. Table 1 below shows each of these components, grouped by the four categories noted above, and includes both the Definition and the Calculation Methodology for each.

Table 1: NEM Methodology Components

NO.	Name	Definition	Calculation Methodology
Col	A	B	C
Generation Related Cost Components			
1	Avoided Energy Costs	"Increase/reduction in variable costs to the Utility from conventional energy sources i.e. fuel use and power plant operations, associated with the adoption of NEM"	"Component is the marginal value of energy derived from production simulation runs per the Utility's most recent Integrated Resource Planning ("IRP") study and/or Public Utility Regulatory Policy Act ("PURPA") Avoided Cost formulation."
2	Avoided Capacity Costs	"Increase/reduction in the fixed costs to the Utility of building and maintaining new conventional generation resources associated with the adoption of NEM."	"Component is the forecast of marginal capacity costs derived from the Utility's most recent IRP and/or PURPA Avoided Cost formulation. These capacity costs should be adjusted for the appropriate energy losses."
3	Ancillary Services	"Increase/reduction of the costs of services for the Utility such as operating reserves, voltage control, and frequency regulation needed for grid stability associated with the adoption of NEM."	"Component includes the increase/decrease in the cost of each Utility's providing of procurement of services, whether services were based on variable load requirements and/or based on fixed/static requirement, i.e., determined by an N-1 contingency. It also includes the cost of future NEM technologies like "smart inverters" if such technologies can provide services like VAR support, etc."
4	Avoided Criteria Pollutants	"Increase/reduction of SOx, NOx, and PM10 emission costs to the Utility due to increase/reduction in production form the Utility's marginal generation resources associated with the adoption of NEM generation if not already included in the Avoided Energy component."	"The costs of these criteria pollutants are most likely already accounted for in the Avoided Energy Component, but, if not, they should be accounted for separately. The Avoided Energy component must specify if these are included."
5	Avoided CO_2 Emission Cost	"Increase/reduction of CO2 emissions due to increase/reduction in production from each Utility's marginal generating resources associated with the adoption of NEM generation."	"The cost of CO2 emissions may be included in the Avoided Energy Component, but, if not, they should be accounted for separately. A zero monetary value will be used until state or federal laws or regulations result in an avoidable cost on Utility system for these emissions."

NO.	Name	Definition	Calculation Methodology
6	Fuel Hedge	"Increase/reduction in administrative costs to the Utility of locking in future price of fuel associated with adoption of NEM."	"Component includes the increase/decrease in administrative costs of any Utility's current fuel hedging program as a result of NEM adoption and the cost or benefit associated with serving a portion of its load with a resource that has less volatility due to fuel costs than certain fossil fuels. This value does not include commodity gains or losses and may currently be zero."
7	Environmental Costs	"Increase/reduction of environmental compliance and/or system costs to the Utility."	"The environmental compliance and/or Utility system costs might be accounted for in the Avoided Energy component, but, if not, should be accounted for separately. The Avoided Energy component must specify if these are included. These environmental compliance and/or Utility system costs must be quantifiable and not based on estimates."
Transmission and Distribution			
8	T & D Capacity	"Increase/reduction of costs to the Utility associated with the expanding, replacing, and/or upgrading transmission and/or distribution energy capacity associated with the adoption of NEM."	"Marginal T&D distribution costs will need to be determined to expand, replace, and/or upgrade capacity on each Utility's system. Due to the nature of NEM generation, this analysis will be highly locational as some distribution feeders may or may not be aligned with the NEM generation profile although they may be more aligned with the transmission system profile/peak. These capacity costs should be adjusted for the appropriate energy losses."
9	Line Losses	"Increase/reduction of electricity losses by the Utility from the points of generation to the points of delivery associated with the adoption of NEM."	"Component is the generation, transmission, and distribution loss factors from either the Utility's most recent cost of service study or its approved Tariffs. Average loss factors are more readily available, but marginal loss data is more appropriate and should be used when available."
Utility Integration & Interconnection Costs			
10	Utility Integration & Interconnection Costs	"Increase/reduction of costs borne by each Utility to interconnect and integrate NEM."	"Costs can be determined most easily by detailed studies and/or literature reviews that have examined the costs of integration and interconnection associated with the adoption of NEM. Appropriate levels of photovoltaic penetration increases in South Carolina should be included."

NO.	Name	Definition	Calculation Methodology
Utility Administration Costs			
11	Utility Administration Costs	"Increase/reduction of costs borne by each Utility to Administer NEM."	"Component includes the incremental costs associated with net metering, such as hand billing of net metering customers and other administrative costs."

Q. WHAT ARE THE CURRENT NEM METHODOLOGY VALUES?

A. Since implementation of the current NEM Methodology under the NEM Settlement, DESC has updated values consistent with the NEM Methodology annually in the fuel proceeding. Most recently, the values were further updated as a result of Order No. 2020-244 in the Company's avoided cost proceeding as shown in Table 2 (and grouped by the four cost categories). Because the values had already been updated as a result of Order No. 2020-244, the Company did not update the values in its 2020 fuel proceeding.

Table 2: Current NEM Value Stack (Annualized $/kWh)

	Components	**Levelized Price ($/kWh)**
Col Row	A	B
1	**Generation Costs**	
2	Avoided Energy Costs	$0.02865[2] (a)
3	Avoided Capacity Costs	$0.00379 (a)
4	Ancillary Services	$0.0000 (a)
5	Avoided Criteria Pollutants	$0.00003 (a)
6	Avoided CO_2 Emission Cost	$0.00000 (a)
7	Fuel Hedge	$0.00000 (a)
8	Environmental Costs	$0.00105 (a)
9	**Transmission and Distribution Costs**	
10	T & D Capacity	$0.00000 (a)
11	Utility Integration & Interconnection Costs	($0.00096) (a)
12	Line Losses	$0.00266[3]
13	**Administrative Costs**	
14	Utility Administration Costs	$0.00000 (a)
15	**Total**	$0.03522 (a)
16	(a) Excludes Line Losses	

Q. DO YOU HAVE ANY RECOMMENDED CHANGES TO THE NEM METHODOLOGY?

[2] Excludes Avoided Criteria Pollutants and Environmental Costs. Should also exclude Avoided CO2 Emissions Costs, but those values are currently set to zero.
[3] Currently based on 7.75% line losses.

A. Yes, I have recommendations on the calculation methodology related to two of the components: Avoided Energy Component and the Lines Losses Component.

Q. WHAT RECOMMENDED CHANGES DO YOU HAVE FOR THE AVOIDED ENERGY COMPONENT OF THE VALUE STACK?

A. We are recommending that Avoided Energy Costs be further segmented to represent the variation in Avoided Energy Costs by season and time of day.

Q. WHAT IS THE REASON FOR THIS RECOMMENDED CHANGE IN THE NEM METHODOLOGY?

A. We recommend this adjustment to better reflect the differences in avoided energy costs and potential variability in the volume of customer-generation in each season and time of day period. Specifically, customer-generation is not constant across the year and across a day, and neither are Avoided Energy Costs. Further delineating Avoided Energy Costs by season and time of use periods and then applying the actual energy produced during those same designated season and time of day periods would better represent the value of customer-generation. The application would be to multiply the time differentiated Avoided Energy Costs by the total energy produced by the customer-generation in those designated time of use periods.

Q. IS THIS RECOMMENDATION CONSISTENT WITH ACT 62?

A. Yes. Specifically, S.C. Code Ann. § 58-40-20(F)(3), which states:

> (3) A solar choice metering tariff shall include a methodology to compensate customer-generators for the benefits provided by their generation to the power system. In determining the appropriate billing mechanism and energy measurement interval, the commission shall consider:
>
> (b) the interaction of the tariff with time-variant rate schedules available to customer-generators and whether different measurement intervals are justified for customer-generators taking service on a time-variant rate schedule

This recommended change to the NEM Methodology is consistent with Act 62's contemplation of time-variant rates because the change recognizes that customer generation is valued based on what time that energy is generated relative to the costs of the system.

Q. WHAT RECOMMENDED CHANGES DO YOU HAVE FOR THE AVOIDED ENERGY LOSSES/LINE LOSSES COMPONENT OF THE VALUE STACK?

A. We recommend first distinguishing Transmission and Distribution losses and then creating a value for Transmission losses that applies to all customer-generation and a Distribution Losses Component that applies to only the customer-generation simultaneously consumed on-site.

Q. PLEASE EXPLAIN WHY YOU ARE RECOMMENDING THIS CHANGE IN METHODOLOGY.

A. The underlying assumption of using a combined transmission and distribution line loss factor is that a kWh from the customer generation resource offsets load at the delivery meter. However, this is not always the case. Although every kWh consumed on the customer's premises does avoid both transmission and distribution losses, those kWh's exported onto the system do not necessarily reduce the losses of energy delivered to other customer meters. In fact, because that exported kWh must be transported across the distribution system, the value of that kWh could be also be eroded by distribution losses, and thus becomes a negative value.

To correct for this, we recommend creating two loss factors: one for Transmission and one for Distribution and then apply both those losses factors to on-site simultaneous consumption, and only applying Transmission losses factor to volumes of exports.

Q. IS THIS RECOMMENDATION CONSISTENT WITH THE NEM SETTLEMENT?

A. Yes. The Avoided Energy Losses/Line Losses Component description in the NEM Settlement notes that "marginal loss data is more appropriate and should be used when available." This methodology change takes a step towards that ideal by looking at losses separately between transmission and distribution and the actual savings of each of those types of losses.

Q. BASED ON YOUR ANALYSIS, SHOULD ANY OF THE COMPONENTS BE ELIMINATED?

A. No. They are all consistent with other, similar, value stack methodologies. For example, New York's Value stack includes an energy avoided costs (Energy Value and is differentiated by time of day as well as location), generation capacity value (Capacity Value), environmental costs value (environmental value of clean kWh), T&D capacity (Demand Reduction Value and Locational System Relieve Value) .

Q. BASED ON YOUR ANALYSIS, DO ANY JURISDICTIONS CONSIDER ADDITIONAL COMPONENTS?

A. Yes. A few jurisdictions consider additional benefits related to 'externality' benefits such as health benefits or reduction in other externalities that may be avoided by carbon free generation. This includes the "direct and indirect economic impacts" discussed earlier in my testimony. However, I must point out that these jurisdictions may include these costs in assessing the cost effectiveness of a program but do not use these costs in rate setting.

Q. SHOULD THESE ADDITIONAL BENEFITS BE INCLUDED IN THE NEM METHODOLOGY?

A. No. First, like "direct and indirect economic impacts," these "externality costs" are very difficult to quantify and highly dependent upon numerous, contentious assumptions. As I noted above, many of those studies only quantify the benefits of solar and not necessarily the difference, or incremental value, of customer generation solar resources versus wholesale or utility scale solar resources.

Second, these "externality costs" are not avoided by the utility. If these "externality costs" are included in setting rates under a NEM program—thus included in the compensation to customers who install generation resources behind the meter—utilities' costs will increase along with the rates. This is, in effect, a "cost shift" that is based on value to one group of customers that is paid for by another group of customers.

Finally, if a utility is required to provide additional compensation for customer generation resources that accounts for these "externality costs," then the utility must charge customers for this additional compensation. This effectively puts the Commission in the position of being a taxing authority with the utilities merely collecting these taxes on behalf of the State. That is, the Commission will tax all utility customers through the utility's rates to generate the revenue necessary to offset the incremental benefits paid to customers with behind the meter generation. In fact, since these customers receive significant State and Federal tax incentives to encourage their investment in these technologies, these 'externality' benefits are already being reflected, to some degree, in these incentives and thus including them directly would result in some double counting.

Q. DID YOU ANALYZE THE COSTS AND BENEFITS OF DESC'S CURRENT NEM OFFERINGS?

A. Yes, we conducted several cost and benefit tests to review the cost-effectiveness of DESC's current NEM offerings.

Q. PLEASE DESCRIBE WHAT COST BENEFIT ANALYSES ARE AND HOW THEY ARE USED IN THIS CONTEXT.

A. Cost benefit analyses are used to evaluate the relationship between costs and benefits of investments made by utilities or customers to manage electricity use behind the customer's meter. The methodologies within the cost benefit analyses generate a series of discounted cash flows related to different components of benefits or costs. Whether any of these discounted cashflows are considered benefits or costs is determined by the perspective of the test. For example, if the test is from the perspective of the participating customer, the benefits are the reductions in electricity bills and incentive payments while costs are any expenditures the customer must make as part of the program. Conversely, these same discounted cash flows for lower energy bills and incentives are a cost to non-participating customers while any costs the utility is now able to avoid as a result of the participating customer's investment is considered a benefit.

The results of a cost benefit analysis a series of metrics that show the net benefits of an investment, in net present value terms, as well as a ratio of absolute value of benefits to absolute value of costs. The former metric indicates the magnitude net benefits, which are benefits less costs. If the value is positive, the investment is yielding a positive "return" relative to similar investments. The latter metric provides an indication of the level of benefits relative to costs. Specifically, a ratio close to 1 indicates the value of costs and benefits are nearly equal, while a number far greater than 1 provides insights that the costs are much lower than benefits (and conversely a value far less than 1 indicates the costs are much larger than benefits).

Q. DID YOU USE A STANDARDIZED METHODOLOGY FOR THE COST BENEFIT ANALYSIS?

A. Yes. Our methodology was based on the "California Standard Practice Manual Economic Analysis of Demand-Side Programs and Projects", October 2001 (Standard Practice). The methodology established in that manual is widely used to evaluate customer programs.

Q. WHY IS THIS METHODOLOGY ACCEPTABLE FOR USE IN EVALUATING NEM?

A. The manual establishes, on page 2, the definition of DSM Categories and Programs as follows:

> This manual employs the use of general program categories that distinguish between different types of demand-side management programs, conservation, load management, fuel substitution, load building and self-generation. Conservation programs reduce electricity and/or natural gas consumption during all or significant

> portions of the year. ‘Conservation” in this context includes all ‘energy efficiency improvements’. An energy efficiency improvement can be defined as reduced energy use for a comparable level of service, resulting from the installation of an energy efficiency measure or the adoption of an energy efficiency practice. Level of service may be expressed in such ways as the volume of a refrigerator, temperature levels, production output of a manufacturing facility, or lighting level per square foot. Load management programs may either reduce electricity peak demand or shift demand from on peak to non-peak periods.
>
> Fuel substitution and load building programs share the common feature of increasing annual consumption of either electricity or natural gas relative to what would have happened in the absence of the program. This effect is accomplished in significantly different ways, by inducing the choice of one fuel over another (fuel substitution), or by increasing sales of electricity, gas, or electricity and gas (load building). Self-generation refers to distributed generation (DG) installed on the customer’s side of the electric utility meter, which serves some or all of the customer's electric load, that otherwise would have been provided by the central electric grid.
>
> In some cases, self-generation products are applied in a combined heat and power manner, in which case the heat produced by the self-generation product is used on site to provide some or all of the customer’s thermal needs. Self-generation technologies include, but are not limited to, photovoltaics, wind turbines, fuel cells, microturbines, small gas-fired turbines, and gas-fired internal combustion engines.

As noted above, the Standard Practice contemplated the use of the evaluation methodologies and resulting cost benefit tests for assessment of self-generation programs. In other words, the methodology we are using is consistent with the methodologies outlined in this manual. Further, DESC uses one of the tests, the Total Resource Cost Test, outlined in this manual in evaluating their Demand Side Management programs.

Q. WHICH METRICS DEFINED IN THE STANDARD PRACTICE MANUAL DID YOU USE IN YOUR COST AND BENEFIT ANALYSIS?

A. We used four of the standard tests defined in Table 4 below.

Table 4: Description of Cost and Benefit Tests

Test	Abbreviation	Description
Total Resource Cost Test	TRC	The Total Resource Cost Test measures the net costs of a program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.
Program Administrator Cost Test	PAC	The Program Administrator Cost Test measures the net costs of a customer program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant.
Participant Cost Test	PCT	The Participants Test is the measure of the quantifiable benefits and costs to the participating customer due to their participation in a program.
Ratepayer Impact Measure Test	RIM	The Ratepayer Impact Measure (RIM) test measures implications on customer bills or rates due to changes in utility revenues and operating costs caused by the program.

Q. WHY ARE THE TESTS INCLUDED IN THE STANDARD PRACTICE MANUAL APPROPRIATE FOR A BENEFIT AND COST ANALYSIS FOR DESC'S CURRENT NEM TARIFF?

A. The tests outlined in the Standard Practice Manual are widely used in evaluation of other customer programs such as Energy Efficiency and Demand Response, which have similar characteristics to NEM programs, particularly since customers install behind the meter technologies to reduce their energy bills. Secondly, as noted above, recently this approach was used in California's recent

NEM Successor Tariff Order Instituting Ratemaking proceeding[4] these tests were the basis for significant valuation and validation for all three investor owned utilities and all intervening parties. Specifically, E3 was contracted by the California Public Utility Commission ("CPUC") to develop a "Public Tool" for all participants to use in evaluating their NEM successor rate options relative to the status quo. The Public Tool used specified benefit and cost components in the benefit cost tests.

Q. PLEASE DESCRIBE THE TOTAL RESOURCE COST TEST IN DETAIL AND WHY IT IS APPLICABLE IN THE EVALUATION OF SOLAR GENERATION EVALUATION.

A. The Total Resource Cost Test measures the net benefits or costs of the customer generation resource option. Using the Value Stack as the basis for benefits and costs, the benefits calculated in the Total Resource Cost Test are the avoided generation supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction. The costs in this test are the program costs paid by both the utility and the participants plus the increase in supply costs for the periods in which load is increased. Thus, all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test. Any tax credits are considered a reduction to costs in this test.

[4] NEM 2.0, Docket No. R.14-07-002.

Q. PLEASE DESCRIBE THE PROGRAM ADMINISTRATOR COST TEST AND WHY IT IS APPLICABLE IN THE EVALUATION OF SOLAR GENERATION EVALUATION.

A. The Program Administrator Cost Test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits.

Q. PLEASE DESCRIBE THE PARTICIPANT COST TEST AND WHY IT IS APPLICABLE IN THE EVALUATION OF SOLAR GENERATION EVALUATION.

A. The Participants Test is the measure of the quantifiable benefits and costs to the customer due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.

Q. PLEASE DESCRIBE THE RATE IMPACT MEASURE TEST AND WHY IT IS APPLICABLE IN THE EVALUATION OF SOLAR GENERATION EVALUATION.

A. The Ratepayer Impact Measure ("RIM") test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.

Q. DID YOUR COST BENEFIT ANALYSIS CONSIDER DIFFERENT CUSTOMER GROUPS?

A. Yes. The cost benefit analysis focused on the two customer sectors, as defined in the Solar Generation Forecast (the "Solar Forecast") sponsored by DESC Witness Robinson,[5] that have the greatest penetration of NEM and customer-generation: Residential Single Family and Small Commercial. This is because the other sectors have large systems and small levels of participation so taking an "average" of those customers could be misleading particularly if a few large customers create a significant portion of that Sector's benefits and costs.

Q. WHAT ARE THE SOURCES OF BENEFITS AND COSTS USED IN THESE TESTS?

A. All benefits and costs used in these tests were directly derived from either current NEM Methodology Values (See Table 1) or the results of the Solar Forecast.

[5] This solar forecast is submitted on behalf of DESC in compliance with the Commission Directive issued in this docket on August 26, 2020.

Specifically, each line item in the value stack can be considered a cost or benefit component to the cost benefit analysis. Further, the Solar Forecast provides inputs regarding system equipment and installation costs, tax incentives and bill savings or lost revenues.

Q. WHAT DURATION OF BENEFITS AND COSTS DID YOU CONSIDER IN YOUR ANALYSIS?

A. We conducted the cost benefit analysis for the twenty-year life of a system installed in 2020.

Q. DID YOU ADJUST ANY NEM METHODOLOGY VALUES BASED ON RECOMMENDED CHANGES TO THE NEM METHODOLOGY?

A. No. However, we did have to make a few adjustments to align these values with other values in the cost benefit analysis to allow for differentiation of certain component's costs or benefits to align with the Standard Practice test.

Specifically, our cost benefit analysis focused on the current state and thus used current NEM Methodology Values. The only modification we made was to use 15-Year levelized value every year of the 20-year term of the evaluation period. This was necessary to align the NEM Methodology Values with the Solar Forecast values, which were over the expected 20-year life of the PV system.

Further, we needed to distinguish each line item in the NEM Methodology as either a cost or a benefit. Specifically, Utility Integration & Interconnection Cost is currently a negative value. Therefore, to align costs and benefits appropriately, we used the absolute value of that component and then designated it as a cost. Also, to ensure the losses are computed correctly for both each benefit and cost in the tests, we computed losses for each component and designated them as a line item cost or benefit. For example, for Utility Integration & Interconnection Costs, the losses linked to those costs should also be considered a line item cost.

Q. DID YOU ADJUST ANY NEM METHODOLOGY VALUES IN PREPARING THE SOLAR FORECAST?

A. No. Our cost benefit analysis used the same assumption for current and future rates, PV equipment costs, PV Operations and Maintenance Costs, Investment Tax Credits and State Tax incentives as well as system output and system size as presented by DESC Witness Robinson. We then generated an annual levelized value for each value component.

Q. DID YOU HAVE TO CALCULATE OR GENERATE ANY INPUTS FOR THE COST BENEFIT ANALYSIS?

A. Yes, we had to calculate three values: On-Site Consumption Bill Savings; Export Credits; and Carry-Over Credits.

Q. PLEASE EXPLAIN EACH OF THESE VALUES AND HOW YOU GENERATED A VALUE.

A. All three were calculated to allow for distinction between line items of costs or benefits for each of the tests. On-Site Consumption Bill Savings is the revenues savings only from the customer simultaneously offsetting customer-generation with behind the meter load. This was computed as the Annual Bill Savings times the ratio of actual 2019 on-site consumption of customer-generation to actual 2019 customer-generation within each month for each customer class as captured in DESC's billing system.

Similarly, the Export Credits were estimated as the Annual Bill Savings times the ratio of actual 2019 exports to grid to actual 2019 customer-generation within each month for each customer class as captured in DESC's billing system.

Finally, Carry-Over Credits were computed as the kWh of Exports credits from other months used in a month to offset bills over the course of the year. Again, using Annual Bill Savings, the average amount of kWh credits from previous months used to offset a monthly bill was estimated as the billing credit from the SFG and the ratio of carry-over credits divided by total customer-generation.

In summary, the sum of On-Site Consumption Bill Savings, Export Credits, and Carry-Over Credits is the total bill savings to the customer. Under the current NEM program, the value per kWh of each of these categories is the customer's retail rate.

Q. PLEASE DESCRIBE THE RESULTS OF YOUR COST BENEFIT ANALYSIS

A. Table 5 shows the estimated annual levelized cost per kWh of customer-generation for each of the components outlined in the NEM Methodology shown in Table 4. Table 6 shows those values by customer class from the SGF Methodology outlined in Table 4. Table 7 shows which of each of these elements are included as costs or benefits for each of the four Standard Practice Tests. Finally, Table 8 shows the Net Benefits (benefits less costs) and Benefit to Cost Ratios (Benefits divided by costs) for each of the customer sectors and each of the cost benefit tests.

Table 5: Benefit and Cost Components (Annualized $/kWh)

	Cost Element	Value	Value for Losses	NEM Table	Difference
Col Row	A	B	C	D	E
1	**Avoided Energy Costs**	0.028648	0.002340	0.028648	-0.000000
2	**Avoided Capacity Costs**	0.003790	0.000310	0.003790	0.000000
3	**Avoided Ancillary Services**	0.000000	0.000000	0.000000	0.000000
4	**Avoided T & D Capacity**	0.000000	0.000000	0.000000	0.000000
5	**Avoided Criteria Pollutants**	0.000030	0.000002	0.000030	0.000000
6	**Avoided CO2 Emission Cost**	0.000000	0.000000	0.000000	0.000000
7	**Avoided Fuel Hedge**	0.000000	0.000000	0.000000	0.000000
8	**Utility Integration & Interconnection Costs**	-0.000960	-0.000078	-0.000960	0.000000
9	**Utility Administration Costs**	0.000000	0.000000	0.000000	0.000000
10	**Avoided Environmental Costs**	0.001052	0.000086	0.001052	0.000000
11	**Avoided Losses**		0.002659	0.002659	0.000000
12	**Subtotal**	0.032561		0.032561	0.000000
13	**Total**	0.035220		0.035220	0.000000

Table 6: Component Value per Customer Class

	Residential	Small Commercial
Self-Generation Bill Savings	0.06584	0.05040
Export Credits	0.06171	0.03525
Export Carryover Benefit	0.00024	0.00200
PV equipment costs	0.16432	0.10562
Lifetime PV O&M	0.01685	0.01744
ITC Tax Benefit	0.05077	0.02446
State Tax Incentive	0.04762	0.02289
Depreciation Tax Benefits	0.00000	0.02023
Interest Deduction Tax Benefit	0.00000	0.01166

Table 7: Designation of Component for Cost Benefit Analysis by Test

Test →	Participant Cost Test	Utility Cost Test	Ratepayer Impact Measure	Total Resource Cost Test
Component ↓	**PCT**	**UCT**	**RIM**	**TRC**
Avoided Energy Costs (AEC)	NA	Benefit	Benefit	Benefit
Avoided Capacity Costs (ACC)	NA	Benefit	Benefit	Benefit
Avoided Ancillary Services (AAS)	NA	Benefit	Benefit	Benefit
Avoided T & D Capacity (ATC & ADC)	NA	Benefit	Benefit	Benefit
Avoided Criteria Pollutants (ACP)	NA	Benefit	Benefit	Benefit
Avoided CO2 Emissions (ACO2)	NA	Benefit	Benefit	Benefit
Avoided Fuel Hedge Costs (AFHC)	NA	Benefit	Benefit	Benefit
Integration & Interconnection Costs (IIC)	NA	Cost	Cost	Cost
Utility Administration Costs (UAC)	NA	Cost	Cost	Cost
Avoided Environmental Costs (AEC)	NA	Benefit	Benefit	Benefit
AEC related Losses	NA	Benefit	Benefit	Benefit
ACC related Losses	NA	Benefit	Benefit	Benefit
AS related Losses	NA	Benefit	Benefit	Benefit
ATC & ADC related Losses	NA	Benefit	Benefit	Benefit
ACP related Losses	NA	Benefit	Benefit	Benefit
ACO2 related Losses	NA	Benefit	Benefit	Benefit
AFHC related Losses	NA	Cost	Cost	Cost
IIC related Losses	NA	Cost	Cost	Cost
UAC related Losses	NA	Benefit	Benefit	Benefit
AEC related Losses	NA	Benefit	Benefit	Benefit
Self-Gen. Bill Savings	Benefit	Cost	Cost	NA
Export Credits	Benefit	Cost	Cost	NA
Export Carryover Benefit	Benefit	Cost	Cost	NA
PV equipment costs	Cost	NA	NA	Cost
Lifetime PV O&M	Cost	NA	NA	Cost
ITC Tax Benefit	Benefit	NA	NA	Benefit
State Tax Incentive	Benefit	NA	NA	Benefit
Depreciation Tax Benefits	Benefit	NA	NA	Benefit
Interest Tax Benefit	Benefit	NA	NA	Benefit

Table 8: Net Benefit Results by Sector (Annualized $/kWh)

	Sector	PCT	UCT	RIM	TRC
Col Row		A	B	C	D
1	Residential	0.11726	0.00000	-0.09112	-0.07655
2	Small Commercial	0.07260	0.00000	-0.05191	-0.01839

Q. PLEASE SUMMARIZE THE IMPLICATIONS OF THE BENEFIT COST ANALYSIS.

A. The results show, that for both the Residential Small Commercial sectors the Participant Cost Tests show net benefits of between 7 and 11 cents per kWh indicating full cost effectiveness for these customers and that average annualized benefits exceed costs. Also, for both sectors, the Program Administrator Cost test shows net benefits of zero. This is because the Program Administrator are made whole through current cost recovery mechanisms.

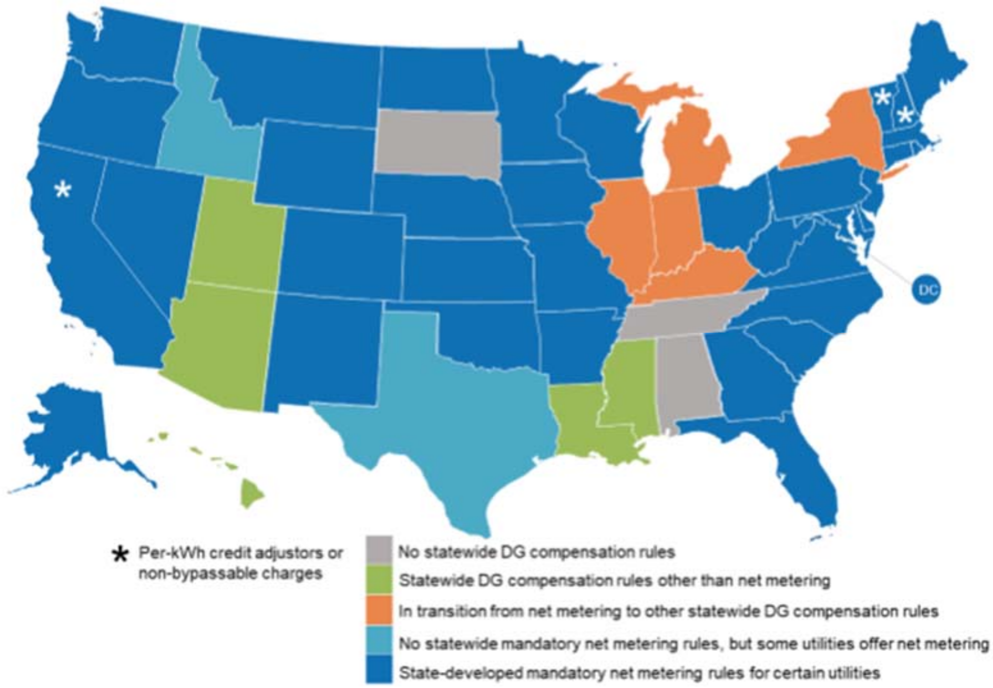
Next, the Rate Impact Measure test shows rates will increase because the benefits from the utility's avoided costs are far less than the lost revenues from the participant's bill savings. This in part is due to the fact that these two customer sectors rely predominately on variable rates to recover costs. As these customers reduce their on-site consumption and receive retail credits for exports they reduce their contribution to costs between total costs reflected in variable retail rates, which include the fixed costs of the assets developed and maintained for these customers, and the utility's avoided costs. The RIM negative net benefits show a potential impact on rates is between 5 and 9 cents for each incremental kWh of customer-generation. This impact is less for the other sectors because those sectors include demand charges that cannot be avoided with NEM. In short, the RIM test is a good indicator of potential cost shifts within and among the customer sectors.

Finally, the Total Resource Cost Test net benefits for both sectors, which indicates the impact on South Carolina, are negative . This is because the costs of installing and maintaining PV equipment to provide a kWh of energy is significantly greater than the Utility's avoided cost for providing a kWh. This implies that the decision to install PV over other wholesale resources, despite the benefits, is less economically efficient.

Q. DID YOU BENCHMARK NEM RATE DESIGN "BEST" PRACTICES IN OTHER JURISDICTIONS IN ACCORDANCE WITH THE COMMISSION DIRECTIVE ISSUED IN THIS DOCKET?

A. Yes. Our benchmarking work is summarized in Exhibit No. __ (ME-1), which documents our research into several states to determine standard practices as well as trends in NEM or Customer-Generation Rate Designs. Figure 1 below shows which states have a NEM rate structure or alternative approaches for rate design for Customer-Generation. The source is 50 States of Solar Q2 2020 Quarterly Report published by NC Clean Energy Technology Center.

Figure 1: Current Net Metering and Distributed Generation Polices



Source: NC Clean Energy Technology Center "50 States of Solar Q2 2020 Quarterly Report"

As Figure 1 shows, all but five states have some form of compensation policy for customer-generation, with two, Idaho and Texas, offering NEM options regardless of state policies. Figure 1 also shows that five states have already moved from NEM structures and another five are transitioning to an alternative tariff structure. Finally, three states, California, New Hampshire, and Vermont have adopted adjustments to their NEM successor rates by introducing adjustments to non-by-passable charges. California also moved to mandatory time of use for all NEM customers.

Throughout the United States, there is a great deal of activity around distributed generation ("DG") compensation and NEM tariff reform. In 2020 alone, over 70 bills regarding DG compensation have been considered by state legislatures with topics ranging from meter aggregation to export credits. This volume of topics being consider by legislators, particularly in a year distracted by COVID-19, is indicative of the amount of change and diversity of options. As such, it is difficult to point to any one best practice. Nevertheless, there are several trends.

First, most jurisdictions recognize the customer's right to instantaneously consume generation from their system directly.

Second, most jurisdictions recognize that these customers create costs related to a utility standing ready to serve that customer when the generation is not available within the hour and across the month. As a result, options to ensure full cost recovery of those costs, particularly for the related grid costs, are being considered. Fixed monthly payments (Fixed Charges) and minimum bills are mechanisms used to ensure all customers, not just customers with customer-generation, pay for the costs associated with being connected to the grid and having real time access to the grid. According to NC Clean Energy Technology Center "50 States of Solar Q2 2020 Quarterly Report", 27 utilities requested increases in residential fixed charges or minimum bills to address this issue of recovering fixed costs for low volume use customers. Both minimum bill and monthly charges are appropriate structures for NEM because NEM requires customers to be charged for their connection to the grid and access to grid services in real time.

A third trend is movement from netting of energy (kWh) to crediting for the value of energy (dollars). Specifically, many states departed from the NEM structures, and others are currently considering alternatives to NEM. The NEM structure allows a customer to 'store' a kWh produced by the customer-generation resource at a time the customer is not consuming to be used by the customer at a later time in the month, or even year. As noted above, in this approach, the value of a kWh of customer-generation is 'deemed' equal to the retail rate and allows customers to use the system as a 'battery' to save energy they produce to be used later while the actual energy is 'exported' to the grid for the utility to either move to another customer or to market to monetize. As a replacement, many jurisdictions have or are considering using a credit, or net billing, approach. This approach values each kWh not used instantaneously on-site at a pre-determined rate. These monetary credits can then be used to offset a customer's bill, creating a very similar effect to NEM. The net billing rate is typically set based on the utility's avoided costs or, like in New York, a "value stack" of the benefits of a customer-generated kWh.

A fourth trend is related to the ownership of the green attributes created by a renewable customer-generation resource. Across the US, the ownership of the REC differs, with many states, like South Carolina, requiring the renewable attribute be assigned to the utility while others, like California, enabling the customer to keep the renewable credit. Of the states we researched, about 90% allow the customer to retain the value of the renewable credit to use to reduce their carbon footprint.

A final trend is study of the cost of service for customers that use the grid to both import electricity to serve the customer's load and export electricity from a customer-generation resource and exploring the use of grid access charges to account for the costs associated with customers having real time access to the grid to provide stand-by power when the customer's generation unit is not operational or accept electricity onto the grid whenever the customer-generation resource output exceeds on-site power needs. In California, the utilities have already or are being required to develop cost of service studies for this purpose. Similarly, New York utilities are currently reviewing the cost of service and cost allocations for these types of 'stand-by' customers. Finally, one utility in Alabama has a tariff that applies to customer-generation that charges these customers approximately $5 for each kW of behind the meter system capacity to account for grid and integration costs related to serving these types of customers. Although contentious and still under debate, an increase in this charge was recently supported by a unanimous vote, increasing to $5.41/kW.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.